AIR EMISSION SOURCE
CONSTRUCTION PERMIT

Source ID No.:	0550023
Effective Date:	DRAFT
Source Name:	Holcomb Station
NAICS:	221112, Fossil fuel power generation (SIC 4911)
Site Location:	Holcomb, Kansas
Site Owner/Operator Name:	Owners (as described below): Holcomb 2, LLC (f/k/a/ Sand Sage Power, LLC) Holcomb 3, LLC Holcomb 4, LLC Operator: Sunflower Electric Power Corporation (Sunflower)
Site Owners/Operators Mailing Address:	Owners and Operator 301 West 13th Street Hays, KS 67601
Contact Person:	Mr. Wayne Penrod Senior Manager, Environment/Production Planning Telephone Number (785)-623-3313

This permit is issued pursuant to K.S.A. 65-3008 as amended.

Description of Activity Subject to Air Pollution Control Regulations

The operator, on behalf of the owners is proposing to install and operate three new 700 (nominal[1]) megawatt (700 MW) coal-fired generating units (Holcomb 2, Holcomb 3, and Holcomb 4) including three steam generators (H2, H3, and H4), three companion cooling towers, three auxiliary boilers, three emergency power generators and associated coal, lime and ash handling equipment, at the site adjacent to the existing Holcomb 1 generating unit owned by Sunflower Electric Power Corporation (Sunflower).

[1] Approximate size of the generating unit, not a reference to gross or net capacity.

Ownership of the individual Holcomb generating units is not specified. One or more of the units may be owned by a single party, while one may be jointly-owned by more than one party. These owners will own and Sunflower will operate the units and the auxiliary and the ancillary facilities which support the generating units to be constructed under this permit.

Holcomb 2 will utilize most of the material handling equipment that was installed with Holcomb 1. A new coal rail unloading system, and a new coal conveyor and crusher system will be installed which will serve both Holcomb 3 and Holcomb 4. Some cross connection of the coal handling systems is anticipated. A new waste powder (flyash and scrubber reactants) storage system will be installed for both Holcomb 3 and 4. All new auxiliary equipment will be designed and installed in accordance with appropriate New Source Performance Standard (NSPS) regulations. New material handling equipment associated with this permit will likewise be designed and installed in accordance with NSPS standards.

The proposed addition will be subject to the requirements of 40 CFR 52.21, Prevention of Significant Deterioration (PSD) as adopted under K.A.R. 28-19-350. The project consists of new units at an existing source for which at least one regulated pollutant is emitted in excess of the PSD significant emission levels. The coal-fired steam generators will be individually subject to the requirements of 40 CFR Part 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for which Construction Commenced after September 18, 1978; to such revisions promulgated on May 18, 2005 and amended June 9, 2006 for mercury when construction commences after January 30, 2004; and to such final revisions for PM, SO_2, and NO_X where construction commences after February 27, 2006. The coal handling system additions will be subject to the requirements of 40 CFR Part 60, Subpart Y, Standards of Performance for Coal Preparation Plants. The auxiliary boilers will be subject to the requirements of 40 CFR Part 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. H2, H3, and H4 generating units are affected sources subject to Title IV of the Federal Clean Air Act. The monitoring system, as required by Title IV and other applicable regulations, may be used to satisfy some of the monitoring requirements of 40 CFR Part 60, Subpart Da as specified therein.

Emissions of oxides of nitrogen (NOx), carbon monoxide (CO), sulfur dioxide (SO_2), volatile organic compounds (VOC), particulate matter (PM), particulate matter less than 10 microns in diameter (PM_{10}), sulfuric acid mist (H_2SO_4), and lead were evaluated for this permit review. This project is subject to the provisions of K.A.R. 28-19-300 (Construction permits and approvals; applicability) because each steam generator individually has the potential-to-emit NO_X, CO, SO_2, VOC, PM, PM_{10}, H_2SO_4 and lead in excess of 40, 100, 40, 40, 25 and 15, 7, and 0.6 tons per year, respectively. The total emission of fluorides from the three steam generators are estimated to be below the annual significance threshold.

Mercury is not regulated under 40 CFR Part 52, and therefore was not included in the PSD review. Emission of mercury is limited at 40 CFR Part 60 Subpart Da and by state only conditions in this permit. Emission limits will be met by blending various coals, or by the injection of powdered activated carbon (PAC), other sorbent or both. PAC or sorbent injection equipment will be installed with each steam generator.

An air dispersion modeling impact analysis, an additional impact analysis, and a Best Available Control Technology (BACT) determination were conducted as a part of the construction permit application process.

Significant Applicable Air Pollution Control Regulations

The main steam generators (H2, H3, and H4), the auxiliary boilers, the coal handling equipment, and the lime storage/handling systems, as proposed, are subject to Kansas Administrative Regulations relating to air pollution control. The following significant air quality regulations were determined to be applicable to this source:

K.A.R. 28-19-11 Exceptions Due to Breakdown or Scheduled Maintenance – as applied to State regulations K.A.R. 28-19-30 through K.A.R. 28-19-32 and K.A.R. 28-19-650.

K.A.R. 28-19-31 Emissions Limitations

K.A.R. 28-19-650 Opacity Requirements

K.A.R. 28-19-275 Special Provisions; Acid Rain Deposition

K.A.R. 28-19-300 Construction permits and approvals; applicability

K.A.R. 28-19-720 New Source Performance Standards, which adopts 40 CFR Part 60 Subpart Y

40 CFR Part 60 Subpart Da-"Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978" as amended February 27, 2006

40 CFR Part 60 Subpart HHHH – "Emission Guidelines and Compliance Times for Coal-Fired Electric Steam Generating Units" as promulgated May 18, 2005

40 CFR 60 Part Subpart IIII – "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines" as proposed July 11, 2005

40 CFR Part 75 - such portions as are applicable to the Clean Air Mercury Rule

40 CFR Part 60 Subpart Db – "Standards of Performance for Industrial-Commercial-Institutional Steam Generating Unit" as amended February 27, 2006.

Air Emission Unit Technical Specifications

The following equipment or equivalent is approved:

1. Each coal-fired steam generator is to be equipped with low-NO_X burners, a separated over-fire air system (SOFA) and a selective catalytic reduction (SCR) process to control NO_X emissions, dry flue gas desulfurization (dry FGD) modules to control SO_2, and H_2SO_4 emissions, and a dry fabric-filter system to control particulate emissions and lead. Activated carbon or sorbent injection, other technology or fuel blending that achieves similar reduction effectiveness will be deployed to control mercury emissions. Maximum design fuel input for each unit to be 6,501 million BTUs per hour (mmBtu/hr) on an average annual basis. Maximum fuel sulfur content will be 0.50 percent on an average annual basis. Fuel to be Powder River Basin (PRB) sub-bituminous coal or other western coal.

2. Additions and improvements to the existing coal unloading, storage, handling and feed system, if any, to be designed to meet the requirements of 40 CFR 60 Subpart Y. All coal conveyors, except the unloading conveyors, will be enclosed to minimize the release of PM emissions. PM emissions from all drop points, including the primary coal crusher, will be captured and controlled by baghouse dust collectors. Wetting agents will be used on the coal pile and other locations, as necessary, to limit the release of fugitive emissions.

3 Additions and improvements to the existing ash transport, loading, storage, and handling systems, if any, to be designed to meet the requirements of K.A.R. 28-19-650.

4 Additions and improvements to the lime unloading, storage, transfer, and preparation systems, if any, to be designed to meet the requirements of K.A.R 28-19-650.

5 Auxiliary boiler(s) to be equipped with low-NO_X burners and flue gas recirculation (FGR). Maximum design heat input for each auxiliary boiler to be 200 mmBtu/hr. Fuel shall be pipeline quality natural gas.

6. One cooling tower sufficient to service each of the H2, H3, and H4 units to be designed with efficient commercially available drift eliminators to reduce aerosol and particulate emissions from the tower.

7. One 1500 kW emergency generator (approximately 1790 horsepower) for each of the H2, H3, and H4 units to be equipped with a catalytic converter designed to meet the requirements of proposed 40 CFR Part 60 Subpart IIII.

Air Emissions Estimates from the Proposed Holcomb Expansion Project

Pollutant Type	Post Permit Potential-To-Emit (Tons per Year)[2]
Nitrogen Oxides (NO_X)	6022
Carbon Monoxide (CO)	12842
Sulfur Dioxide (SO_2)	8543
Volatile Organic Compounds (VOC)	301.3
Particulate Matter (PM/PM_{10})	3397
Elemental Lead	1.40
H_2SO_4	360
Mercury (Hg)	0.842

Air Emission Limitations

1. K.A.R. 28-19-650(a)(3): Opacity of visible emissions from each emissions unit after control, if any, shall not exceed 20 percent on a 6-minute average basis.

2. H2, H3, and H4 Main Steam generators:

   On and after the required performance tests referenced in 40 CFR Part 60 and K.A.R. 28-19-212, the emissions of each pollutant that is expressed as lbs/mmBtu or as lbs/MWh shall not exceed the limit referenced hereunder. Test requirements and compliance with this standard is described in the section entitled Compliance and other Performance Testing.

   "Day" in the 30-day rolling average limits for NOx and SO_2 shall have the same meaning as "boiler operating days" as defined in 40 CFR 60.41Da for units constructed after February 28, 2005.

   The operator of these units shall use good air pollution control practices to minimize emissions during initial startup and shakedown operations[3] of the steam generators. Shakedown operations will be completed prior to the required NSPS performance testing.

[2] Potential-to-emit estimates are based on operation at full capacity for 8760 hours per year while in compliance with all conditions of this permit.
[3]These operations may include, but are not limited to, first fires, proof of interlocks, steam blow, chemical cleaning, initial turbine roll and shakedown operations and testing of the steam generator and turbine equipment.

Subsequent startup practices shall include the use of natural gas as an ignition fuel, low sulfur solid fuels, and the placing in service, and removing from service, of control technology equipment in accordance with manufacturers' recommendations consistent with long-term sustainable operation of the steam generator and for the individual air pollution control equipment installed.

Equipment is to be placed in service as specified in the appropriate paragraphs below.

a. The operator of these units shall not emit or cause to be emitted from any unit NO_X emissions exceeding 0.07 pounds per million BTU heat input (lb/mmBtu) on a 30-day rolling average basis, excluding periods of startup, shutdown, and malfunction. This emission limit is less than the NSPS emission limit of 1.0 lb/MWh in 40 CFR 60.44Da(e).

   During the first 18 months following initial startup, the first unit (or multiple units that initiate operation contemporaneously) constructed under this permit shall not emit or cause to be emitted any NO_X emissions exceeding 0.10 lb/mmBtu on a 30-day rolling average basis, excluding periods of startup, shutdown, and malfunction, in lieu of the 0.07 lb/mmBtu limit in item (2a). During this period, the owner or operator must operate and maintain the SCR system and demonstrate "best practices" to achieve 0.07 lb/mmBtu. Best practice includes but is not limited to: evaluation of control equipment capabilities and characteristics to assure proper and effective operation, effective evaluation of catalyst efficiency, evaluation of CEM data to assure optimal process and control equipment operation for practical reduction of NO_X emissions, and data obtained from evaluations conducted at similar facilities.

   During the first 12 months following initial startup, subsequent unit(s) constructed under this permit shall not emit or cause to be emitted any NO_X emissions exceeding 0.10 lb/mmBtu on a 30-day rolling average basis, excluding periods of startup, shutdown, and malfunction. The operator shall demonstrate best practices to achieve the 0.07 lb/mmBtu as are identified for the first unit.

   NO_X emissions during startup and shutdown will be controlled by the use of low-NO_X burners, separated over-fire air systems, and a selective catalytic reactor. Startup is defined as the time period after coal fires are established and before the SCR inlet temperature is consistently above 650˚F. If a prolonged startup is experienced (SCR is not placed in service when the proper temperature is reached), the operator will notify KDHE of the conditions contributing to such prolonged startup in accordance with the malfunction notification provisions. If the equipment vendor specifies a design temperature greater than 650˚F, then the temperature shall be subject to revision in coordination with KDHE..

b. The operator of these units shall not emit or cause to be emitted from any unit SO_2 emissions exceeding 0.095 lb/mmBtu on a 30-day rolling average basis. Such limitation shall not apply during periods of startup and shutdown, or when emergency conditions defined in 40 CFR 60.41Da exist and the procedures under 40 CFR 60.48Da(d) are implemented.

The operator of these units shall not emit or cause to be emitted from any unit SO_2 emissions exceeding 1.4 lb/MWh on 30 successive boiler operating days (as defined in 40 CFR 60.41Da).

SO_2 emissions shall be controlled by the use of the sulfur dioxide scrubber. Startup is defined as the time period after coal fires are established and before the fabric filter inlet temperature is above 185˚F. In no case will scrubber operations commence before the fabric filter is placed in service.

c. Emissions of PM[5] for these units shall not exceed 0.012 lb/mmBtu from any unit, averaged over three (3) runs of at least 120 minutes in duration, excluding periods of startup, shutdown, and malfunction. This emission limit is less than the NSPS emission limit of 0.015 lb/mmBtu in 40 CFR 60.42Da(c).

PM emissions shall be controlled by the use of a fabric filter.

d. Emissions of PM_{10}[6] shall not exceed 0.035 lb/mmBtu from any unit, averaged over six (6) runs of at least 120 minutes in duration, excluding periods of startup, shutdown, and malfunction. If the initial performance test demonstrates that an emissions limitation of 0.018 lb/mmBtu is consistently achievable, this limitation shall supersede the PM_{10} emission limitation of 0.035 lb/mmBtu.

e. If the initial performance test for each unit does not indicate that a PM_{10} emission limitation of 0.018 lb/mmBtu is consistently achievable, then either the emission limitation indicated by the initial performance test, contingent upon approval by KDHE, shall be incorporated into a revised permit, or additional testing shall be accomplished (in accordance with "Compliance and other Performance Testing" Paragraphs 7 and 8 below) to determine the revised emissions limitation. Additional testing, if done,

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[5] The term "PM" as used in this permit means that particulate matter emitted by a steam generator that can be quantified by analysis under Reference Method 5 set forth in Appendix A of 40 C.F.R. Part 60.

[6] The term "PM_{10}" as used in this permit means that particulate matter (existing as solid, liquid, and gaseous form) emitted by a steam generator that can be quantified by analysis either under Reference Method 5 and 202 or under 201 (or 201A) and 202 or by such methods approved by both KDHE and Region VII of the U.S. EPA.

shall be accomplished in 12 months from the date of completion of the initial performance test. Thereafter a new emissions limitation shall be determined by KDHE and incorporated into a revised permit, with such new emissions limitation to be deemed effective as of the date of the initial performance test.

f. Emissions of Volatile Organic Compounds (VOC) for any unit shall not exceed 0.0035 lb/mmBtu, averaged over the period specified in the test protocol approved by KDHE.

g. Emissions of Carbon Monoxide (CO) for any unit shall not exceed 0.15 lb/mmBtu, averaged over the period specified in the test protocol approved by KDHE.

h. Emissions of total elemental Lead (Pb) for any unit shall not exceed 16.4 lb/TBtu averaged over the period specified in the test protocol approved by KDHE.

i. Emissions of total sulfuric acid mist (H_2SO_4) for any unit shall not exceed 0.004 lb/mmBtu averaged over the period specified in the test protocol approved by KDHE.

j. Emissions of mercury for any unit shall not exceed 0.097 lb/GWh over a 12 month rolling average, excluding periods of startup, shutdown, and malfunction, when burning sub-bituminous coal. (40 CFR 60Da(a)(2)(ii)

Emissions of mercury for any unit shall not exceed 0.020 lb/GWh over a 12 month rolling average, excluding periods of startup, shutdown, and malfunction, when burning bituminous coal. (40 CFR 60Da(a)(1)

The operator shall reduce mercury emissions to 0.020 lb/GWh, as determined on a 12 month rolling average basis, when burning sub-bituminous coal, or any blend of coals and/or other supplementary fuels, excluding periods of startup, shutdown, and malfunction.

This emission limit is less than the NSPS emission limit established at 40 CFR 60.45Da(a)(2)(ii). In no case shall this NSPS limitation, or other appropriate NSPS emission rate established as of June 9, 2006, for any fuel or combination of fuels identified in 40 CFR 60.45Da(a), be exceeded.

NSPS standards referenced in 40 CFR Part 60, Subpart Da specifies limits to the emission of NO_X, SO_2, PM, and Hg from these steam generators individually. Because the limits expressed above in Conditions 2.a, 2.c, and 2.j are more restrictive than the NSPS requirements those NSPS emission limits are not included in this permit.

3. Coal System:

40 CFR Part 60, Subpart Y limits visible emissions from any new or modified coal handling equipment to 20 percent opacity.

4. Ash System:

K.A.R. 28-19-650 limits visible emissions from any new or modified ash system equipment to 20 percent opacity.

5. Lime System:

K.A.R. 28-19-650 limits visible emissions from any new or modified lime system equipment to 20 percent opacity.

6. Cooling Tower:

The cooling tower for each unit will be equipped with commercially available high efficiency drift eliminators with a maximum total liquid drift not to exceed 0.0005 percent of circulating water flow rate. Compliance with this requirement is demonstrated by maintaining records of the vendor-guaranteed maximum total liquid drift. No chromium-based water treatment chemicals will be used in the circulating water system and thus the requirements of 40 CFR Part 63, Subpart Q shall not apply.

Total dissolved solids in the circulating water for each of the three cooling towers associated with these sources shall not exceed 9,000 ppm by volume.

Permit Conditions

1. Coal handling equipment is subject to regulation under 40 CFR Part 60 Subpart Y, namely: coal processing and conveying equipment (including breakers and crushers), and coal storage systems (except for open storage piles). New coal handling equipment includes conveyors, a new crusher house, new transfer points and a new stacker/reclaimer system. The equipment, either newly constructed or modified (if any), shall be enclosed and vented to a baghouse with a 99% manufacturers' guarantee control efficiency.

2. Newly constructed or modified equipment for fly ash and lime systems, if any, shall be enclosed and vented to a baghouse with a 99% manufacturers' guaranteed control efficiency.

3. The baghouses for the newly constructed or modified equipment shall be in place and continuously operated, except during periods of malfunction, breakdown, or necessary repairs, to control emissions of PM and PM_{10} whenever the associated material handling equipment is in operation. Maintenance and repair of the baghouses shall be conducted in a manner to minimize emissions.

4. The total fuel consumed in each auxiliary boiler shall not exceed 175,000 MCF/calendar-year. NSPS emission standard for NO_X referenced in 40 CFR Part 60, Subpart Db does not apply for boilers of less than 250 MMBtu/hr operated at an annual capacity factor of less than 10% (40 CFR 60.44b(k)) while firing natural gas. Should the owner or operator ever exceed the 10% annual capacity factor (uses more than 175,000 MCF/calendar year), the schedule for starting the initial performance test would commence as soon as the exceedance has occurred.

5. The pre-controlled emission rate of sulfur dioxide (SO_2), as measured at the scrubber inlet, for any of the H2, H3, and H4 units shall not exceed 1.23 lbs SO_2/MMBtu on an average annual basis.

6. The emergency diesel generators, shall be equipped with a standard catalytic converter and shall not be operated for more than 500 hours per year.

Compliance and Other Performance Testing

1. Within 60 days after achieving the maximum production rate for each steam generator, but not later than 180 days after initial start-up, the owner or operator shall conduct performance tests to demonstrate compliance with the applicable conditions and limitations set forth in this permit for SO_2, NO_X,CO, VOC, and PM, and furnish KDHE a written report of the results of such performance tests.

2. Within 60 days after achieving the maximum production rate for each steam generator, but not later than 180 days after initial start-up, the owner or operator shall conduct Method 9 performance test(s) to demonstrate compliance with the opacity limitations set forth for the new or modified coal, lime and ash handling equipment and furnish KDHE a written report of the results of such performance test(s).

3. Within 18 months after initial start-up of the first steam generator, the owner or operator shall conduct performance test(s) to demonstrate compliance with the applicable conditions and limitations set forth in this permit for elemental lead and H_2SO_4, and shall furnish to KDHE a written report of the results of such performance test(s).

4. Within 60 days after achieving the maximum production rate for the first steam generator, but not later than 180 days after initial start-up, the owner or operator shall demonstrate compliance with the cooling tower total dissolved solids concentration limit and furnish KDHE a written report of the results of such performance test(s). For the six (6) months thereafter, the owner or operator shall perform monthly analyses to verify the limitation is not exceeded. Once this has been verified, the analyses shall be performed semiannually.

   For each subsequent generating unit, the owner or operator shall perform monthly analyses for six months after initial startup to verify the limitation is not exceeded. Once this has been verified, the analyses shall be performed semiannually.

5. Continuous monitoring systems and monitoring devices required for each steam generator shall be installed and operational prior to conducting compliance performance tests under 40 CFR 60.8. Verification of operational status, at a minimum shall include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the devices as required by 40 CFR 60.13.

6. In conducting the compliance performance tests required by this permit, the reference test methods and procedures outlined in K.A.R. 28-19-212 and 40 CFR 60.48Da shall be used to demonstrate compliance with the limitations and conditions set forth in this permit.

7. Within 180 days after commencing commercial operation of the first unit, the owner or operator shall conduct a performance test of PM_{10} emissions and furnish KDHE a written report of the results of such test within 60 days of completion of said test. If, after evaluating the test data, the report reasonably concludes that the emissions limitation of 0.018 lb/mmBtu for PM_{10} in Condition 2.e. of the Air Emissions Limitations section above may not be achievable, then the owner or operator may perform additional testing to determine an emission limitation for PM_{10} that the steam generator can and should be able to consistently comply with such limit while operating in a manner of good operating practices and regularly scheduled maintenance of the steam generator, pollution control equipment and ancillary equipment.

8. If the owner or operator requests that the PM_{10} emissions limitation be adjusted through additional testing, it shall include within the report required by Paragraph 7, a complete plan for establishing a PM_{10} measurement protocol, including the method(s), number of test runs, and a tentative timeline, not to exceed 12 months, necessary to establish by appropriate statistical methods the new PM_{10} emissions limitation for the unit under the range of normal operating conditions. Such plan shall include a requirement for quarterly reporting, to include an analysis of test results, unit operating parameters, air pollution control device operating parameters, fuel conditions, and other such matters as might influence the test results.

   KDHE shall take measures to adjust the PM_{10} emissions limitation to that which is determined by the test results, as follows: KDHE shall establish a revision to the PM_{10} emissions limitation for each steam generator which: (i) insures that there will be no exceedence of either the NAAQS or the PSD increment consumption allowance for PM_{10}, (ii) is based upon a statistical analysis, and (iii) is consistently achievable on a sustained and long term basis with the exercise of due care and good operating practices

   Within 180 days after commencing commercial operation or 60 days after the first unit's emission limit has been established, whichever is later, the owner or operator shall conduct a performance test of PM_{10} emissions for the second and third unit and furnish KDHE a written report of the results of such test within 60 days of completion of said test.

Monitoring Requirements

1. Within 60 days after achieving the maximum production rate at which each steam generator will be operated, but not later than 180 days after initial start-up of the steam generator, the owner or operator of each unit shall install and operate a continuous monitoring system to monitor and record emissions of SO_2, $NO_{X,}$ and Hg as required by 40 CFR 60.49Da and of opacity or alternatives to monitoring procedures or requirements approved by the Administrator of the U.S. EPA pursuant to 40 CFR 60.13(i).

2. The owner or operator shall use opacity monitoring equipment as an indicator of continuous particulate matter control device performance and demonstrate compliance with §60.42Da(b) and conduct the performance test annually. The owner or operator using a fabric filter to comply with the applicable emission limits shall install, calibrate, maintain, and continuously operate a bag leak detection system according to 40 CFR 60.48Da(o)(4). As an alternative to the above, the owner or operator may elect to install, certify, maintain, and operate a continuous particulate matter emission monitoring system measuring particulate matter emissions discharged from the affected facility to the atmosphere and shall record the output of the system as specified 40 CFR 40.48Da(p).

3. All continuous monitoring systems required by 40 CFR Part 60 shall meet the applicable requirements of 40 CFR 60.13, Appendix B, and Appendix F for certifying, maintaining, operating and assuring quality of the systems, and, where applicable, with the requirements of 40 CFR Part 75.

Recordkeeping

1. The operator shall maintain records of the occurrence and duration of any start-up, shut-down, or malfunction in the operation of each unit subject to 40 CFR 60 any malfunction of any air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative. These requirements are described in 40 CFR 60.7(b).

2. The operator shall maintain records of the occurrence and duration of any emergency condition in the operation of H2, H3, and H4 scrubber. These requirements are described in 40 CFR 60.7(b).

3. The operator of H2, H3, and H4 shall maintain records of the occurrence and duration of any periods during which a continuous monitoring system or monitoring device is inoperative. These requirements are described in 40 CFR Part 75.

4. The operator shall maintain records of the reports, notifications, and performance tests required by this permit.

   All of the above records shall be maintained on site for a period of 5 years.

Reporting

Reports demonstrating compliance shall be submitted to the KDHE in the same engineering units as stated in the applicable requirements.

1. Items that are required to be reported quarterly (opacity excess emission reports per 40 CFR 60.51Da(i)) shall be submitted to KDHE and postmarked by the 30th day following the end of each calendar quarter.

2. Items that are required to be reported semiannually (NO_X and SO_2 per 40 CFR 60.51Da(b) and Hg per 40 CFR 60.51Da(g)) shall be submitted to KDHE and postmarked by the 30th day following the end of each calendar half or, upon agreement by KDHE and proper certification, submitted electronically per 40 CFR 60.51Da(k) by the 30th day following the end of each calendar quarter.

3. Items that are required to be reported annually (natural gas consumption of the auxiliary boiler and average annual scrubber inlet SO_2 concentration) shall be submitted to KDHE and postmarked by the 30th day following the end of each calendar year.

4. Within 60 days after completion of the PM_{10} performance test, the owner or operator of the first unit shall furnish KDHE a written report of the results of such test. If the owner or operator requests emission limitation adjustment for PM_{10} in accordance with this permit, the owner or operator shall continue to furnish quarterly reports on progress towards developing data sufficient to establish such new limitation until the conclusion of the process defined in this permit.

5. Within 90 days after the 18 months NO_X trial period of the first unit (12 months for subsequent units), if the data demonstrates that the 0.07 lb/mmBtu limit cannot be met, then the owner or operator of said unit shall submit a performance assessment report and, as part of this report, the minimum NO_X emission rate, in lb/mmBtu, that can be achieved during long-term load dispatch operation, and justification thereof. In that event, “best practices” shall continue to be used until an alternative emission rate is effective.

6. The excess emissions and monitoring systems performance report and/or a summary report for opacity per 40 CFR 60.51Da(h) shall, for each generating unit, be submitted to the KDHE as required by 40 CFR 60.7(c). The summary report form shall contain the information and be in the format as specified in 40 CFR 60.7(d). Written reports of excess emissions shall include the following information:

a. The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, the date and time of commencement and completion of each time period of excess emissions, and the process operating time during the reporting period.

b. Specific identification of each period of excess emissions that occurs during start-ups, shut-downs, and malfunctions, the nature and cause of any malfunction (if known), the corrective action taken or preventive measures adopted. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero span checks and the nature of the system repairs and adjustments.

c. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

7. Malfunction

The Owner or Operator must notify KDHE by telephone, facsimile, or electronic mail transmission within two (2) working days following the discovery of any failure of air pollution control equipment, process equipment, or of the failure of any process to operate in a normal manner which results in an increase in emissions above any allowable emission limit stated in “Air Emission Limitations” in this permit. In addition, the Owner or Operator must notify KDHE in writing within ten (10) days of any such failure. The written notification shall include a description of the malfunctioning equipment or abnormal operation, the date of the initial malfunction, the period of time over which emissions were increased due to the failure, the cause of the failure, the estimated resultant emissions in excess of those allowed in “Air Emission Limitations”, and the methods utilized to mitigate emissions and restore normal operations.

Compliance with this malfunction notification shall not excuse excess emissions resulting from such event.

Notification

1. The Bureau of Air and Radiation shall be notified when installation of the equipment is complete so an evaluation may be conducted to verify compliance with applicable regulations.

2. K.A.R. 28-19-720 (40 CFR 60.7(a)) requires that written notifications of the following be submitted to KDHE:

a. The date construction of each affected facility under 40 CFR Part 60, associated fuel and ash handling equipment, and the associated air pollution control systems is commenced. The notification is to be postmarked no later than 30 days after such date.

b. The actual date of initial startup of each affected facility under 40 CFR Part 60. The notification is to be postmarked within 15 days after such date.

c. The date when the initial performance testing of each affected facility under 40 CFR Part 60 is to commence. The notification is to be postmarked no less than 30 days prior to such date.

The attached NSPS notification form will be used to submit the above required notifications.

Title IV and Acid Rain Requirements

Each generating unit is subject to certain Title IV and Acid Rain requirements. A complete Acid Rain permit application shall be submitted in accordance with the deadlines specified in 40 CFR Part 72. Notification regarding applicable monitoring equipment will be made as required.

The owner or operator will submit the applicable equipment monitoring plan, and will notify KDHE and EPA when the CEMS certification tests are to be performed.

Title V Requirements

An application for significant modification to the current Title V permit, shall be submitted within one year of the initial startup of the first generating unit.

General Provisions

1. Construction can continue on the units approved in this document in accordance with the provisions of 40 CFR 52.21(r)(2) and K. A. R. 28-19-301(c) for a period of 96 months from the date of issuance of the permit.

2. Construction shall not commence for any unit approved in this document if construction has not commenced within 18 months of the effective date of this document without written approval from KDHE. The owner or operator shall submit for KDHE approval information for re-evaluating BACT and submit an analysis demonstrating you do not significantly contribute to a violation of the NAAQS or increment.

3. A construction permit or approval must be issued by KDHE prior to commencing any construction or modification of equipment or processes which result in an increase in potential-to-emit equal to or greater than the thresholds specified at K.A.R. 28-19-300.

4. Upon presentation of credentials and other documents as may be required by law, the operator shall allow a representative of the KDHE (including authorized contractors of the KDHE) to:

a. enter upon the operator’s premises where a regulated facility or activity is located or conducted or where records must be kept under conditions of this document;

b. have access to and copy, at reasonable times, any records that must be kept under conditions of this document;

c. inspect at reasonable times, any facilities, equipment (including monitoring and control equipment), practices or operations regulated or required under this document; and

d. sample or monitor, at reasonable times, for the purposes of assuring compliance with this document or as otherwise authorized by the Secretary of the KDHE, any substances or parameters at any location.

5. The emission units or stationary sources that are the subject of this document shall be operated in compliance with all applicable requirements of the Kansas Air Quality Act and the Federal Clean Air Act.

6. This document does not relieve the operator of the obligation to obtain other approvals, permits, licenses or documents of sanction that may be required by other federal, state or local government agencies.

7. Issuance of this document does not relieve the owner or operator of any requirement to obtain an air quality operating permit under any applicable provision of K.A.R. 28-19-500.

Permit Engineer

_______________________ _______________

Rick Bolfing, P.E. Date Signed
Environmental Engineer
Bureau of Air and Radiation

RJB:

c: NWDO
C-6706

PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

PERMIT SUMMARY SHEET

Permit No.: 0550023

Source Name: Sunflower Electric Power Corporation - Holcomb Units 2, 3, and 4

Source Location: Holcomb Generating Station, S32, T24S, R33W, Holcomb, KS 67851

Area Designation:

K.A.R. 28-19-350, Prevention of significant deterioration of air quality, affect new major sources and major modifications to major sources in areas designated as "attainment" or "unclassifiable" under section 107 of the Clean Air Act (CAA) for any criteria pollutant (Table 1-1). The State of Kansas is classified as attainment for the National Ambient Air Quality Standards (NAAQS) (see Table 1-2) for all the criteria pollutants.

The Holcomb area in Finney County, Kansas, where this construction is taking place is in attainment for all the criteria pollutants.

Project description:

Sunflower Electric Power Corporation plans to build three generating facilities located in Holcomb, Finney County, Kansas. The generating station will install Holcomb Units 2, 3, and 4 respectively, each unit being a super critical 700 megawatt (MW) (6501 mmBtu/hr heat input) pulverized coal (PC) fired boiler. The existing coal, lime, and ash handing equipment with the addition of equipment to double throughput capability will be utilized. Three new cooling towers, three natural gas fired auxiliary boiler and three emergency generators shall be added. The Holcomb Units 2, 3, and 4 boilers will fire Powder River Basin (PRB) sub-bituminous coal, low sulfur bituminous coal as primary fuel and natural gas as a backup fuel.

Significant Applicable Air Emission Regulations

This source is subject to Kansas Administrative Regulations relating to air pollution control. The application for this permit was reviewed and will be evaluated for compliance with the following applicable regulations:

1. K.A.R. 28-19-300. Construction Permits and Approvals. Requires “Any person who proposes to construct or modify a stationary source or emissions unit shall

obtain a construction permit before commencing such construction or modification."

2. K.A.R. 28-19-350 Prevention of significant deterioration of air quality. "The provisions of K.A.R. 28-19-350 shall apply to the construction of major stationary sources and major modifications of major stationary sources in the areas of the state designated as an attainment area or an unclassified area for any pollutant under the procedures prescribed by section 107(d) of the federal clean air act (42 U.S.C. 7407 (d))."

3. K.A.R. 28-19-720 New Source Performance Standards: The additional coal handling system is subject to 40 CFR Part 60, Subpart Y- "Standards of Performance for Coal Preparation Plants".

4. The three PC fired boilers are subject to 40 CFR Part 60 Subpart Da - "Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978" as amended February 27, 2006, portions of 40 CFR 60 subpart HHHH – "Emission Guidelines and Compliance Times for Coal-Fired Electric Steam Generating Units" as promulgated May 18, 2005 and portions of 40 CFR Part 75 that are applicable to the Clean Air Mercury Rule; and the three natural gas fired auxiliary boilers are subject to 40 CFR subpart Db – "Standards of Performance for Industrial-Commercial-Institutional Steam Generating Unit" as amended February 27, 2006.

Air Emissions from the Project:

Potential-to-emit of one of the PSD regulated pollutants from the new Sunflower Electric Power Corporation generating station exceeds 100 tons per year. Hence, this facility is considered to be a major stationary source under provisions of K.A.R. 28-19-350.

The potential-to-emit from the new facility (i.e. Holcomb Units 2, 3, and 4 boilers, the additional coal, lime and ash handing equipment, the natural gas auxiliary boilers, the emergency generators, and the new cooling towers) are listed in Tables 1-3 and Appendix D of the permit application. Proposed potential-to-emit of NOx, SO_2, CO, PM/PM_{10}, Sulfuric Acid Mist, Lead, and VOCs were compared with the Significant Emission Rates for PSD applicability for the criteria and non-criteria pollutants. The increase in potential-to-emit is above the PSD significance level and would be reviewed under the PSD regulations. Total Fluorides were below the PSD significance levels.

The proposed project of the boilers, the additional coal, lime and ash handing equipment, the natural gas fired auxiliary boilers, the emergency generators, new cooling towers and the associated fugitive emissions along with the operating scenarios are given in Part 1, Section 2.1 through 2.2.6 and Material Handling flow diagrams in Appendix C of the application. The uncontrolled potential-to-emit used for BACT analysis of the boiler uses 0.25 pounds per million

British thermal units (lb/mmBtu) for NOx, 1.23 lb/mmBtu for SO_2, 6.154 lb/mmBtu for particulate matter, 0.15 lb/mmBtu for CO, 0.0035 lb/mmBtu for VOC, 0.004 lb/mmBtu for Sulfuric Acid Mist, and 16.4 lb/TBtu for lead, which corresponds to typical emission values for PC boilers firing PRB coal. These values are given in Tables 4-9 for NOx, Table 4-13 for SO_2, and Tables 4-17 particulate matter.

The after-controls potential-to-emit of the boiler is calculated using low-NOx burners (LNB) and separated over-fire air (SOFA) equipment along with selective catalytic reduction (SCR) for NOx control, fabric filter for PM_{10} control, and dry flue gas desulfurization (FGD) and ancillary equipment for SO_2 control. These values are given in Table 4-9 for NOx, Table 4-13 for SO_2, and Table 4-17 for particulate matter. The increase in emissions represents all that are contemporaneous with the proposed changes.

Hence, this project will be a major stationary source resulting in a net significant increase of NOx, SO_2, CO, PM/PM_{10}, Sulfuric Acid Mist, Lead, and VOC. This project will be subject to the various aspects of K.A.R. 28-19-350 such as the use of best available control technology, ambient air quality analysis, and additional impacts upon soils, vegetation and visibility.

Best Available Control Technology (BACT)

BACT requirement applies to each new or modified affected emissions unit and pollutant emitting activity. Also, individual BACT determinations are performed for each pollutant emitted from the same emission unit. Consequently, the BACT determination must separately address, for each regulated pollutant with a significant emissions increase at the source, air pollution controls for each emissions unit or pollutant emitting activity subject to review. Sunflower Electric Power Corporation was required to prepare a BACT analysis for KDHE's review according to the process described in Attachment A. KDHE's evaluation of the BACT for the proposed boiler, coal, lime and ash handing equipment, auxiliary boiler and new cooling towers' analysis is presented in Attachment B.

In short KDHE has concurred with the Sunflower Electric Power Corporation for the following:

For the PC fired boilers:

BACT for Nitrogen dioxide is 0.07 lb/mmBtu, thirty day rolling average, excluding startup, shutdown and malfunction (as defined in the permit), for the proposed boilers. The boilers shall use low-NOx burners (LNB) and separated over-fire air (SOFA) equipment along with selective catalytic reduction (SCR). During the first 18 months following initial startup of the first boiler, the emission limit shall be 0.12 lb/mmBtu utilizing LNB, SOFA, and SCR. If, with good faith efforts in the operation of the installed NOx control equipment, and with sufficient demonstration that other steam generating units of similar size, with similar control equipment, burning PRB sub-bituminous fuel are unable to achieve the 0.07 lb/mmBtu emission rate, then such NOx emission limitation of 0.07 lb/mmBtu shall be subject to revision in accordance with the EPA's July 5, 1985 memorandum titled "Revised Draft Policy of Permit Modifications and Extensions".

BACT for carbon monoxide is 0.15 lb/mmBtu. BACT for CO is good combustion practices. If the CO and NO_X emission limits cannot be achieved simultaneously, the NO_X emission limit shall take precedence and the CO BACT emission limit, based on a review of performance test results, shall be subject to revision in accordance with the EPA's July 5, 1985 memorandum titled "Revised Draft Policy of Permit Modifications and Extensions".

BACT for sulfur dioxide is 0.095 lb/mmBtu, thirty day rolling average, excluding periods of startup and shutdown (as defined in the permit), and when emergency conditions as defined in 40 CFR 60.41Da exist and the procedures under 40 CFR 60.48Da(d) are implemented. The boilers are also subject to the requirements of 40 CFR Part 60 Subpart Da. The boilers shall use dry flue gas desulfurization (dry FGD) system and low sulfur coal.

BACT for volatile organic compounds (VOC) is 0.0035 lb/mmBtu. BACT for VOC is good combustion practices. If the VOC and NO_X emission limits cannot be achieved simultaneously, the NO_X emission limit shall take precedence and the VOC BACT emission limit, based on a review of performance test results, shall be subject to revision in accordance with the EPA's July 5, 1985 memorandum titled "Revised Draft Policy of Permit Modifications and Extensions".

BACT for particulate matter (PM) and particulate matter less than 10 microns (PM_{10}) is 0.012 lb/mmBtu and 0.018 lb/mmBtu, respectively, excluding periods of startup, shutdown, and malfunction (as defined in the permit). If the PM_{10} limit of 0.018 is not consistently achievable, then the PM_{10} limit, based on a review of performance test results, shall be subject to revision in accordance with the EPA's July 5, 1985 memorandum titled "Revised Draft Policy of Permit Modifications and Extensions". BACT for PM/PM_{10} is a fabric filter.

BACT for total elemental lead for any unit shall not exceed 16.4 lb/TBtu, averaged over the period specified in the test protocol.

BACT for sulfuric acid mist for any unit shall not exceed .004 lb/mmBtu, averaged over the period specified in the test protocol.

BACT for the auxiliary boilers for NOx emissions is low NOx burners and for SO_2 is combusting only pipeline natural gas.

BACT for other pieces of equipment include the following: catalytic converters for emergency generators, high efficiency drift eliminators for the cooling towers, baghouses and chemical / water suppression for material handling systems.

Mercury (Hg) Limits for PC fired Boilers

Although Hg is no longer considered a pollutant regulated under New Source Review, the source has agreed to a limit of 0.020 lb/GWh while burning subbituminous coal or blends, a limit far more stringent than 40 CFR 60 Subpart Da. The emission limitation expressed in the third paragraph of the permit's **Air Emission Limitations** paragraph 2j, is as stringent as the most recently permitted coal fired generating units. Should the installed equipment be confirmed to be in proper working order, and should it be found unable to cause the established emission limitation to be consistently achieved, whether related to mercury in fuel, or to fuel type or to other undetermined reasons, then the mercury limit shall be subject to revision in accordance with the EPA's July 5, 1985 memorandum titled "Revised Draft Policy of Permit Modifications and Extensions". In no case shall such limit exceed the limits referenced in 40 CFR Part 60 Subpart Da for Hg.

Ambient Air Impact Analysis

The owner or operator of a proposed source or modification must demonstrate that allowable emission increases from the proposed source, in conjunction with all other applicable emissions increases or reductions, would not cause or contribute to air pollution in violation of:

1) any national ambient air quality standard (NAAQS) in any air quality control region; or

2) any applicable maximum allowable increase over the baseline concentration in any area.

Sunflower Electric Power Corporation used EPA approved dispersion modeling guidelines (incorporated as Appendix W of 40 CFR 51) to predict the ambient air impacts. A modeling protocol for the Sunflower Electric Power Corporation Holcomb Units 2, 3, and 4 boilers addition Ambient Air Quality Impact Analysis was submitted to KDHE on April 27, 2005. The modeling protocol was discussed in the Pre-PSD Application Meeting on March 22, 2006.

The ISCST3 model with ICS-PRIME was used to determine the maximum predicted ground-level concentration for each pollutant and applicable averaging period resulting from various operating loads.

Pollutant emission rates (lb/hour) were selected from the boiler data contained in Table 5-7 of the application to produce worst case dispersion conditions and highest model predicted concentrations (i.e. lowest exhaust temperature, lowest exit velocity, and highest emission rate). Table 5-6 of the application shows the boiler stack parameters at modeled load levels used in the ambient impact analysis. The most recent five (5) years of meteorological data available, 2000-2004, of surface and upper air was used in the modeling.

Tables 5-15 through 5-17 of the application contain the screening model results for NOx, CO, SO_2, PM_{10}, and lead compared to the modeling significance thresholds.

The SO_2 screening analysis maximum concentrations for Units 2, 3, and 4 exceeded the modeling significance thresholds for both 3-hour and 24-hour averaging periods. The SO_2 screening analysis was run with various combinations of one unit experiencing maintenance activity while the others continued to operate normally. Maintenance activities significantly increase the SO_2 emission rate for that unit. The maximum predicted concentrations were found to be 216.9 micrograms per cubic meter (ug/m^3) and 21.18 ug/m^3 for the 3-hour and 24-hour averaging periods, respectively. The significance levels for SO_2 are 25 and 5 ug/m^3 for the 3-hour and 24-hour averaging periods, respectively.

The PM_{10} screening analysis maximum concentrations for the active and inactive pile utilization scenarios exceeded the modeling significance thresholds for both 24-hour and annual averaging periods. The maximum predicted concentrations were found to be 17.99 micrograms per cubic meter (ug/m^3) and 2.11 ug/m^3 for the 24-hour and annual averaging periods, respectively. The significance levels for PM_{10} are 5 and 1 ug/m^3 for the 24-hour and annual averaging periods, respectively.

All modeled concentrations for NOx, CO, and lead were less than the modeling significance thresholds for all averaging periods.   The NOx maximum predicted concentration was 0.53 ug/m^3 compared to significance threshold of 1 ug/m^3 for an annual averaging period. The CO maximum predicted concentration was 269.8 ug/m^3 compared to significance threshold of 2000 ug/m^3 for a 1-hour averaging period. The CO maximum predicted concentration was 64.04 ug/m^3 compared to significance threshold of 500 ug/m^3 for an 8-hour averaging period. The lead maximum predicted concentration was 0.00028 ug/m^3. Lead does not have a modeling significance threshold. The modeled concentration is less than the monitoring significance threshold of 0.1 ug/m^3 for lead for a quarterly averaging period.

The screening analysis indicated that additional air quality analysis was required to determine whether potential SO_2 and PM_{10} emissions from the proposed project are expected to cause a significant deterioration of air quality in the Holcomb, Kansas area. A full impact analysis is required to demonstrate compliance with the PSD Class II increment (the whole state of Kansas is designated as a Class II area) and NAAQS.

The expanded receptor grid was established to determine the entire significant impact area, and all SO_2 increment and NAAQS sources (see Table 5-19 of the application) were included in the modeling runs. Table 5-21 of the application shows the SO_2 Class II increment analysis modeling results. All maximum concentrations were below the PSD Class II increment. The maximum predicted concentrations were found to be 234.0, 45.3, and 4.69 ug/m^3 for the 3-hour, 24-hour, and annual averaging periods, respectively. The PSD Class II increment levels for SO_2 are 512, 91, and 20 ug/m^3 for the 3-hour, 24-hour, and annual averaging periods, respectively. Table 5-22 shows the SO_2 NAAQS analysis modeling results. All results, when combined with ambient background concentrations, were below the NAAQS. Ambient background concentrations were 385.7, 159.6 and 16.96 ug/m^3 for 3-hour, 24-hour, and annual averaging periods. The highest predicted total concentrations were 602.0, 204.9, and 20.71 ug/m^3 for 3-hour, 24-hour, and annual averaging periods. The NAAQS for SO_2 are 1300, 365, and 80 ug/m^3 for 3-hour, 24-hour, and annual averaging periods.

The PM_{10} screening model indicated that concentrations dropped below the PSD Modeling Significance Threshold well within the existing receptor grid of 10 kilometers. Therefore, an expanded receptor grid was not required for PM_{10}. The receptor grid for the expanded analysis was composed of a reduced receptor field using only receptors with a significant modeling impact. The NAAQS and increment sources were then incorporated into the model, including emissions from the operation of Holcomb Unit 1. Two scenarios were modeled to demonstrate compliance with the 24-hour and annual NAAQS and PSD Class II increments: the Active Pile Utilization and Inactive Pile Utilization.

Although there were modeled 24-hour and annual PSD increment exceedances for PM_{10}, the construction and operation of H2, H3, and H4 will not cause or contribute significantly to the modeled exceedances. Therefore, no further modeling is required for Class II increment or NAAQS compliance.

Additional Impact Analysis:

Sunflower Electric Power Corporation was required to provide an analysis of the impairment to visibility, and impacts on plants, soils and, vegetation that would occur as a result of this project and to what extent the emissions from the proposed modification impacts the general commercial, residential, industrial and other growth.

Visibility Impairment Analysis

Sunflower Electric Power Corporation conducted a visibility degradation analysis for the NO_x and particulate matter emissions from the proposed modification. Sunflower Electric Power Corporation used the document "Workbook for Plume Visual Impact Screening and Analysis", EPA 450/4-88-015, September 1988, and the EPA approved dispersion modeling procedure "VISCREEN" for guidance. A visibility analysis is performed for Class I (visibility-sensitive) areas located within 100 kilometers of a proposed facility. There are no Class I areas in Kansas. The analysis was done at nearest PSD Class I area, which is Great Sand Dunes National Wilderness Area which is located approximately 400 kilometers west of Holcomb. The VISCREEN model results indicate no exceedance of the perceptibility or plume contrast either outside or inside of the Class I area boundaries.

In accordance with KDHE guidance, a visibility impairment analysis was also conducted at the nearest sensitive area, Scott Lake, located approximately 80 kilometers to the north of the plant. A Level-1 visibility impairment analysis was performed for Scott Lake and for the city of Holcomb. The composite worst case hourly emission rate over all modes of operation for NOx and PM from the modifications were input into the model, along with the most conservative meteorological conditions. Scott Lake and the city of Holcomb's models indicate the potential for exceedances of color change and perceptibility values. However, no criteria have ever been established for Class II areas. It is unclear how much Class I criteria should be applied to other areas.

Impacts on Vegetation

In accordance with 40 CFR 52.21(o)(1), the owner shall provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the modification to the source. Sunflower Electric Power Corporation determined that the proposed facility and the associated increases of NO_2, SO_2, CO, PM_{10}, VOC /ozone, trace elements, and acid gases are not expected to have significant effects on vegetation.

Air pollutants can affect vegetation through direct absorption through the foliage, or uptake from the soil of trace elements deposited in the soil. The effects of air pollution on vegetation can include visible damage to foliage and fruit, changes in metabolic function, adverse changes in plant activity, and crop yield reduction. The effects of air pollutants on vegetation fall into three categories: acute (short exposure to high concentration), chronic (lower concentration over months or years), and long term (abnormal changes to ecosystems and physiological alterations in organisms that occur gradually over very long time periods).

The United States Department of Interior (USDOI) has published a document called Impacts of Coal Fired Power Plants on Fish, Wildlife, and their Habitats. This document was used to consider the effects of NOx, SO_2, CO, PM_{10}, VOC /ozone, trace elements, and acid gases on vegetation. Sunflower Electric Power Corporation conducted a survey of the vegetation located in the vicinity of the modification, which indicated the predominant types of vegetation are pasture and crop land. Switchgrass, little bluestem, big bluestem, Indian grass, and Canada wild rye are found in pastures and meadows. Wheat, corn, soybeans, and alfalfa are the predominant row crops. Trees occur in hedgerows, creek beds, and along the Arkansas River. At the Holcomb Generating Station, vegetation is disturbance-tolerant weedy species. Turf grass is planted in lawn areas.

The impact of NOx on vegetation is discussed in detail in Part 7.0 Section 1.5.1 of the permit application. The most significant effects from NOx are not with the toxicity of gases themselves, but the secondary pollutants that are produced when NOx reacts with airborne hydrocarbons and/or water. NOx air dispersion modeling was conducted to estimate the vegetation impacts from predicted NOx ground level concentrations. NOx may under certain circumstances deleteriously impact vegetation. Typical leaf injury responses include interveinal necrotic blotches. Injury thresholds vary by species and dose, and would be in the range of 3760 ug/m^3 for four hours for tobacco to 7380 ug/m^3 for tomatoes, beans, and sunflowers. A common, weedy plant found in Kansas, lambs quarters, was not injured for two hours at concentrations of 1.9 ug/m^3. Short term fumigations of 1-hour, 20-hours, and 48-hours at NOx concentrations of 940 to 38,000 ug/m^3, 470 ug/m^3, and 3000 to 5000 ug/m^3, respectively, have been shown to deter photosynthesis of a number of herbaceous (tomato, oats, alfalfa) and woody plants. Long term exposures of phytotoxic doses of NOx ranged from 280 to 560 ug/m^3. All the above listed concentrations are greater than the annual and estimated hourly and 24-hour NOx emissions modeled to occur in the vicinity of the facility. From these results it can be concluded that the NOx emissions from this facility will not have an adverse affect on the vegetation in the area.

The impact of CO on vegetation is discussed in detail in Part 7.0 Section 1.5.2 of the permit application. Concentrations of CO are not typically detrimental to vegetation, and have not been found to produce detrimental effects on plants at concentrations below 114,500 ug/m^3 for exposures from one to three weeks (see references in application). Therefore, the NAAQS were used for comparison with modeled concentrations to predict any CO effects on vegetation. Modeling results indicate that H2, H3, and H4 will not exceed the NAAQS for CO. Through compliance with state and federal regulations and the NAAQS for CO, the potential and real adverse vegetation effects of CO emissions from the proposed project have been avoided to the maximum extent possible.

The impact of particulate matter and trace elements on vegetation is discussed in detail in Part 7.0 Section 1.5.3 of the permit application. Sources of particulate due to the proposed project include material handling activities, unloading, conveyance, drop points, storage piles, and movement of heavy equipment on unpaved roads. The emission sources are low height and low velocity, so they contribute to very localized deposition of PM_{10}. Coal combustion has wider dispersion. PM_{10} sources can potentially affect vegetation in several ways. Emissions may physically block plant and tree stomates, or may affect leaf adsorption and reflectance (which hinders heat exchange and photosynthesis). Trace elements in PM_{10} may be toxic to plants. The physical effects of PM_{10} are acted on by wind and rain, and the toxicity is determined mostly by soil and plant characteristics. Plant toxicity from trace elements is mainly based on the interaction between soil and plants and occurs from plant uptake of trace elements deposited in the soil. The concentration of PM_{10} has been compared to the NAAQS for predicting the physical / non-toxicity affects on vegetation. EPA has stated that "for most types of soil and vegetation, ambient concentrations of criteria pollutants below the secondary national ambient air quality standards (NAAQS) will not result in harmful effects" (see reference in permit application). The maximum predicted off-site concentrations (see Figures H-16 through H-19 of the permit application) are well below the maximum allowable NAAQS, and therefore are not expected to negatively impact vegetation.

The impact of sulfur dioxide is discussed in detail in Part 7.0 Section 1.5.4 of the permit application. SO_2 emissions come from combustion of coal in the proposed boilers. Many factors contribute to vegetation effects of SO_2, including atmospheric conditions. SO_2 impacts are analyzed primarily through dispersion modeling to predict ground level concentrations from the proposed project. Short and long term exposures may have detrimental effects on many plant species, and several studies have been conducted studying the effects of SO_2 on vegetation (see application for references). Symptoms of SO_2 injury in leaves are interveinal necrotic blotches in angiosperms and red brown banding in gymnosperms. A number of the plant species studied include those in the Holcomb area. Injury threshold concentrations vary by species and dose: 131-5240 ug/m^3 for 8-hours, 393-3930 ug/m^3 for 2-hours, 1310 ug/m^3 for 4 hours. SO_2 modeled concentrations were significantly lower for the proposed project at 216.9 ug/m^3 for 3-hours, 21.2 ug/m^3 for 24-hours. Long term exposures in the range 43-1198 ug/m^3 had some negative effects, but SO_2 modeled concentrations were significantly lower at 0.649 ug/m^3 (see references in application). Boilers in this project are utilizing BACT to minimize SO_2 emissions, complying with the NAAQS and state and federal regulations, and have emissions below damage thresholds available in referenced literature. Therefore, SO_2 concentrations are not expected to exceed adverse impact levels on vegetation.

The impact of VOCs and ozone is discussed in detail in Part 7.0 Section 1.5.5 of the permit application. VOCs result primarily from products of incomplete combustion during the combustion of coal. VOC does not have a NAAQS level for comparison, therefore, the one-hour and 8-hour NAAQS for ozone are considered. Ozone is formed in a photochemical reaction with the precursors NOx (impacts previously discussed) and VOCs. Ozone is not directly emitted.

Background concentrations of ozone range from 145-155 ug/m^3 in the western and central areas of Kansas. These concentrations do not injure plants. Chronic exposures to concentrations of greater than or equal to 196 ug/m^3 of ozone can negatively affect vegetation, and reduction in growth and photosynthesis of trees can occur at ozone levels of less than 200 ug/m^3 (see application for references). It is difficult to determine the contribution H2, H3, and H4 will have on local or regional ambient ozone concentrations. Photoreactive modeling runs would need to be performed to estimate the ozone impacts resulting from VOC and NOx emissions from this project. It is unlikely that concentrations in the vicinity of the plant would exceed NAAQS levels. The 8-hour NAAQS for ozone is 85 ppb, making the potential contribution of the plant to ozone levels in the immediate area negligible.

The synergistic effects of pollutants on vegetation are discussed in detail in the permit application Part 7.0 Section 1.5.6. Air pollutants can act together to cause injury to or decrease the functioning of plants. Concentrations of pollutants in studies referenced are substantially higher than those occurring as a result of this project. Consequently, no synergistic effects of the air pollutants are expected to inhibit vegetation at or near the Holcomb Generating Station.

Impacts on Soils

Two soil types are mapped at or near the project site (Harner *et al.* 1965). They include:

- Tivoli fine sand
- Tivoli-Vona loamy fine sands

Both soil types are deep, noncalcareous, very sandy soils in steep, duny terrain. The oils are low in fertility and drain very easily. Water is absorbed quickly, and consequently, runoff is very low. Blowout of the soil is prevalent where vegetation is lacking. Erosion often is a problem.

Sulfates and nitrates caused by SO_2 and NOx deposition on soil can be beneficial and detrimental to soils depending on its composition. However, given the low emission levels and the sandy soils in the vicinity of the project, H2, H3, and H4 should not significantly affect the soils in the vicinity of the project.

Growth In Commercial, Residential and Industrial activity

This modification at the Holcomb facility will stimulate an increase in the local labor force during the construction phase in the Holcomb area, but the increase will be temporary, short lived, and will not result in permanent/significant commercial and residential growth occurring in the vicinity of the Holcomb. During the construction phase of H2, H3, and H4, approximately 1,400 people will be employed for various periods of time and in various capacities. Of those, approximately 90 percent will be in the construction sector with the balance in other disciplines such as engineering, consulting, technical services, and procurement. A large work force with the requisite construction skills is not available in the local area. Skilled workers are available in the larger metropolitan areas including Kansas City, Amarillo, Denver, Wichita and Topeka. Because an adequate pool of needed workers is not available within reasonable commuting distance of the site, we expect that most construction personnel will make use of local rental units.

Operation of the facility will require approximately 66 additional employees over current staffing levels. Most of these positions would be recruited locally (within 50 miles of the facility). A portion of the new employees, estimated to be less than half, could choose to relocate with a subsequent increase in permanent residences to areas nearer the facility. These new residences are not anticipated to add appreciably to air emissions in the vicinity of the facility.

No new local industrial facilities related to H2, H3, and H4 are anticipated. An increase in commercial activity related to transportation of coal and lime to the facility and removal of by-products materials (bottom ash) would occur; however, any emissions increases would be from mobile sources and are not part of this analysis. Therefore, H2, H3, and H4 are not anticipated to have sustainable negative impacts to the area based on collateral growth.

Attachment A

KEY STEPS IN THE "TOP-DOWN" BACT ANALYSIS

STEP 1: **IDENTIFY ALL POTENTIAL AVAILABLE CONTROL TECHNOLOGIES**.

The first step in a "Top-Down" analysis is to identify, for the emission unit in question, "all available" control options. Available control options are those air pollution control technologies or techniques with a PRACTICAL POTENTIAL FOR APPLICATION to the emissions unit and the regulated pollutant under review. This includes technologies employed outside of the United States. Air pollution control technologies and techniques include the application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant.

STEP 2: **ELIMINATE TECHNICALLY INFEASIBLE OPTIONS**.

The technical feasibility of the control options identified in Step 1 is evaluated with respect to the source-specific (or emissions unit specific) factors. In general, a demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

STEP 3: **RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS.**

All remaining control alternatives not eliminated in Step 2 are ranked and then listed in order of over-all control effectiveness for the pollutant under review, with the most effective control alternative at the top. A list should be prepared for each pollutant and for each emissions unit subject to a BACT analysis. The list should present the array of control technology alternatives and should include the following types of information:

1) control efficiencies;
2) expected emission rate;
3) expected emission reduction;
4) environmental impacts;
5) energy impacts; and
6) economic impacts.

STEP 4: **EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS**.

The applicant presents the analysis of the associated impacts of the control option in the listing. For each option, the applicant is responsible for presenting an objective evaluation of each impact. Both beneficial and adverse impacts should be discussed and, where possible, quantified. In general, the BACT analysis should focus on the direct impact of the control alternative. The applicant proceeds to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. In the event the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be fully documented for the public record. Then the next most stringent alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology cannot be eliminated.

STEP 5: **SELECT BACT**.

The most effective control option not eliminated in Step 4 is proposed as BACT for the emission unit to control the pollutant under review.

Attachment B
KANSAS DEPARTMENT OF HEALTH AND ENVIRONMENT'S EVALUATION OF SUNFLOWER ELECTRIC POWER CORPORATION HOLCOMB UNITS 2, 3, AND 4 PROPOSED BACT OPTIONS

Sunflower Electric Power Corporation evaluated the BACT analysis to control emissions from Holcomb Units 2, 3, and 4 boilers and three auxiliary boilers and emergency diesel generators. The Holcomb boilers will fire sub-bituminous coal and low sulfur bituminous coal. The proposed operating scenario for the Holcomb boilers includes the firing of coal for 8760 hours per year. The auxiliary boilers will fire pipeline quality natural gas and operation is based on a 10% annual utilization. The diesel generators will operate (other than for testing) only during periods of internal plant electrical emergencies. For this analysis, each diesel generator is assumed to operate 500 hours annually.

NOx BACT for the Holcomb PC boilers

Nitrogen dioxide control methods were divided into two categories: 1) In-combustor NOx formation control and in-combustor control with post-combustion controls. The different types of emission controls reviewed by Sunflower Electric Power Corporation are as follows:

In Combustor type:

Low NOx burners (LNB) and Over-fire Air (OFA) (40% reduction)

In Combustor with post Combustion:

LNB and OFA plus Selective Catalytic Reduction (SCR) (50% reduction)
LNB and OFA plus Selective Catalytic Reduction (SCR) (60% reduction)
LNB and OFA plus Selective Catalytic Reduction (SCR) (72% reduction)

Low NOx combustion systems are designed to reduce the availability of oxygen in the primary combustion zone. This is achieved by staged combustion using LNB in combination with OFA. LNB operation involves decreasing the amount of air introduced into the primary combustion zone, thereby creating a fuel-rich, reducing environment and lowering the temperature, both of which generally suppress NOx formation. OFA further reduces NOx formation by introducing the remaining air required for combustion through separate ports at higher elevations in the boiler, again at lower temperatures, thus limiting production of additional NOx.

The SCR process consists of injecting ammonia (NH_3) into the boiler fuel gas and passing the flue gas through a catalyst bed where the NOx and NH_3 react to form nitrogen and water vapor. Typically, a SCR reactor is located between the economizer and the air heater in order to ensure the optimum operating temperature. The ammonia is injected after the economizer and prior to the catalyst bed. The actual performance of a SCR system varies significantly depending on the volume of catalyst, SCR inlet NOx level, operating temperature, age of the catalyst and the level of ammonia slip that is technically acceptable. The major difference in theses designs (varying percent reduction between options) is the volume of catalyst in the SCR. An area of concern with SCR control is the use of ammonia in conjunction with a catalyst bed to control NOx. There are some unreacted ammonia emissions, which increase with catalyst age, and these emissions pose some environmental concerns.

Please refer to the BACT analysis presented in Part 4 of the application for a more thorough evaluation of possible BACT.

KDHE reviewed the EPA's BACT/LAER/RACT Clearing house and other recently permitted facilities and noted the BACT emission limits of other pulverized coal fired boilers nationwide. Data indicated that recent installation of pulverized coal fired boilers utilized LNB/OFA with SCRs. The PSD regulations requires BACT which requires the source to evaluate the control options for economic feasibility along with the impact on environment and energy use. The economic analysis was conducted according to EPA's guidance document. Installation of an SCR will cost Sunflower Electric Power Corporation between $2,887 and $2,777 per ton of NOx removed. Use of anhydrous ammonia is not environmentally beneficial because of "ammonia slippage" which is unavoidable due to the imperfect distribution of the reagent and catalyst deactivation.

SO_2 BACT for the Holcomb PC boilers

Emissions of SO_2 can be controlled by limiting sulfur content in the fuel or by post-combustion flue gas desulfurization (FGD) system. Sunflower Electric Power Corporation is utilizing low sulfur coal with an average sulfur content of 0.5%. In addition, FGD systems were evaluated as part of the BACT analysis. The FGD systems evaluated were as follows:

Wet FGD (93% removal)
Dry FGD (92% removal)
Dry FGD (90% removal)

Wet FGD has the potential to achieve the lowest emissions among the available technologies. However, wet FGD is not normally applied to PRB coals. In addition, wet FGD is less effective in controlling total particulates, PM_{10}, fine particulates and HAPs than dry FGD since the absorbers in a wet FGD system are located downstream of the particulate control equipment. The maximum ground concentration for all pollutants (including sulfuric acid mist), except SO_2, will be 5 to 10 percent higher with a wet FGD compared with a dry FGD because a wet FGD has lower stack temperatures and velocities. An important issue, especially for facilities located in Western Kansas, is the increase in the amount of water necessary for the wet FGD system. Lastly, the energy required to operate the wet FGD is approximately 2.0% of the proposed unit's generation, almost twice as much energy required for a dry FGD system.

As stated earlier, dry FGD systems are better at controlling pollutants other than SO_2. This is because the particulate control device is located downstream of the dry FGD. The cost of the dry FGD varies between $1206/ton (90% reduction) and $1212/ton (92% reduction) compared with $1431/ton for the wet FGD. However, an incremental cost of over $24,000 per additional ton of SO_2 removed was estimated for a wet FGD compared to a dry FGD.

While the wet FGD can provide the lowest emissions from Holcomb, significant environmental considerations, economics and technological suitability argue for the selection of dry FGD with a 92% reduction of SO_2 as BACT for Holcomb.

PM/PM_{10} BACT for the Holcomb PC boilers

The control option analyzed for particulate control were as follows:

Fabric filter (99.78% reduction)
Electrostatic precipitator (ESP) (99.68% reduction)

A fabric filter is the preferred particulate control device for location downstream of the spray dryer in the dry FGD system because the passage of the flue gas through the dust cake on the bags provides enhance removal of SO_2. Although the capital cost of the ESP is higher than the fabric filter, the total annualized cost of installing and operating a fabric filter is somewhat higher. Since the fabric filter has a higher collection rate and aids in the removal of SO_2, it was selected as BACT for particulate control.

CO BACT for the Holcomb PC boilers

Over-fire air can provide an element of Carbon Monoxide (CO) control as it allows further burn-out of the pollutant. Otherwise, the best identified to control CO emissions from a coal-fired boiler is through the use of appropriate combustion control techniques. Control technologies such as CO catalysts are not available for use on a solid fuel-fired boiler. Catalytic reduction for CO is also not technically feasible because ash in the gas stream will destroy the catalyst after a very short period of operation. Combustion controls to achieve CO emissions of 0.15 lb/MmBtu should be considered BACT for Holcomb.

VOC BACT for the Holcomb PC boilers

Volatile Organic Compounds (VOC) controls consist of combustion controls. Good combustion practices can insure limits of 0.0035 lb/MmBtu for Holcomb.

BACT for the Auxiliary Boilers

Nitrogen oxides and sulfur dioxide were analyzed for control under BACT. The auxiliary boiler is a 200 MmBtu/hr, natural gas fired unit used to provide steam for the main unit during periods of startup and shutdown or during periods of very inclement weather. The boiler will be equipped with low-NOx burners. In order to avoid the limitations of 40 CFR 60 subpart Db, this unit shall be restricted to operate less than 10% of it full load capability annually. The

BACT for sulfur dioxide shall be the burning of only pipeline quality natural gas.

BACT for the Emergency Diesel Generators

The diesel generators will operate (other than for testing) only during periods of internal plant electrical emergencies. For this analysis, each diesel generator is assumed to operate 500 hours annually, burn low sulfur diesel fuel (< 0.05% S) and be equipped with a standard catalytic converter.

Notice Concerning Proposed Kansas Air Quality
Construction Permit and Public Hearing

Notice is hereby given that the Kansas Department of Health and Environment (KDHE) is soliciting comments regarding a proposed air quality construction permit. Sunflower Electric Power Corporation (Sunflower) has applied for an air quality construction permit in accordance with the provisions of K.A.R. 28-19-300 to construct three (3) new 700 MW coal-fired steam generating units and associated ancillary equipment (Holcomb expansion) at their generating station located in Holcomb, Kansas. Emission of particulate matter (PM), PM equal to or less than 10 microns in diameter (PM_{10}), volatile organic compounds (VOCs), oxides of nitrogen (NOx), sulfur dioxide (SO_2), carbon monoxide (CO), elemental lead (Pb), and sulfuric acid mist (H_2SO_4) were evaluated during the permit review process.

The proposed permit is to be issued in accordance with the provisions of K.A.R. 28-19-350, *Prevention of Significant Deterioration* (PSD) which adopt the federal standards, procedures and requirements of 40 CFR 52.21 by reference. These air quality regulations apply to major stationary emission sources located in areas designated as “attainment” under the federal Clean Air Act (CAA). Attainment areas are areas where the air quality meets or is better than the national ambient air quality standards (NAAQS).

The PSD regulations require evaluation of emission reduction techniques to identify the best available control technology (BACT) for each pollutant for which the emission rate exceeds the PSD significant level. The purpose of BACT is to affect the maximum degree of reduction achievable, taking into account energy, environmental and economic impacts for each pollutant under review. Evaluation of the estimated emissions for the proposed Holcomb expansion project indicates that the emission rate of oxides of nitrogen, sulfur dioxide, carbon monoxide, particulate matter, volatile organic compounds, lead, and sulfuric acid mist all exceed the significance levels. Sunflower conducted the required BACT analyses. The department has reviewed Sunflower’s BACT analyses and concurs with its findings that low NOx burners and overfire air with selective catalytic reduction is BACT for NOx, dry flue gas desulfurization (dry FGD) is BACT for SO_2 and H_2SO_4 and fabric filters is BACT for Pb, PM and PM_{10} for the Holcomb expansion project.

An ambient impact analysis was performed on the air emissions of PM_{10}, NOx, SOx, and CO from the Holcomb expansion project. The analysis demonstrated no significant impact on ambient air quality for NOx, and CO. A more detailed analysis for SOx indicated that the emissions would not contribute to any violation of ambient air standards and under worst case demonstrated that 49.8% of the Class II increment for SO_2 was consumed. Detailed analysis showed PM_{10} values would not contribute to any violation of ambient air standards but were above the Class II increment for PM_{10} (30 ug/m^3, 24 hr). All of these receptors that indicated the exceedance were outside of the significant impact area for the Holcomb expansion project.

An analysis of visibility was conducted for the Great Sand Dunes National Monument, the closest federal class I area at approximately 400 km to the west of the facility. The VISCREEN model results indicate no exceedances of the perceptibility or plume contrast either inside or outside of the Class I boundaries. Analysis of the Scott Lake Class II area, located approximately 80 km to the north, was also performed. Although some of the screening analysis were exceeded, no criteria have ever been established for a Class II area. No adverse impacts on soils and vegetation in the area were expected. Any federal land manager who has reason to believe they may have a class I area adversely impacted by the emissions from the proposed project has the opportunity to present KDHE with a demonstration of the adverse impact on the air quality-related values of the federal class I area during the comment period.

A public comment period has been established to allow citizens the opportunity to express any concerns they may have about this proposed permitting action. The public comment period is to begin on September 21, 2006 and end at 5:00 pm on October 30, 2006. All comments should be submitted in writing to Rick Bolfing, Bureau of Air and Radiation, 1000 SW Jackson, Suite 310, Topeka, KS 66612-1366 or presented at the public hearing.

A public hearing to receive comments on the proposed issuance of the draft air quality construction permit is scheduled at the County Commission room in the Finney County Office Building at 311 North 9th Street in Garden City, Kansas on Tuesday, October 24, 2006 at 7:00 pm. A second hearing on the proposed issuance of the draft air quality construction permit is scheduled in Azure Room (4th floor – west) of the Curtis State Office Building at 1000 S.W. Jackson, Topeka, Kansas 66612 on Thursday, October 26, 2006 at 9:00 am. Accommodations will be available for individuals with language translation and special needs. Please notify Rick Bolfing, in writing, by October 18, 2006 as to the nature of the accommodation required and at which location the need exists.

A copy of the proposed permit, permit application, all supporting documentation, and all information relied upon during the permit application review process are available for public review for a period of 30 days from the date of publication during normal business hours (8:00 AM to 5:00 PM) at the KDHE, Bureau of Air and Radiation (BAR), 1000 SW Jackson, Suite 310, Topeka, KS 66612-1366. Also a copy of the proposed permit only can be reviewed, at the KDHE Northwest District Office, 2301 East 13th Street, Hays, Kansas 67601. To obtain or review the proposed permit and supporting documentation, contact Rick Bolfing, (785)296-1576 at the central office of the KDHE and to review the proposed permit only, contact the Air Quality District Representative at (785)625-5663 in the KDHE Northwest District Office. The standard departmental cost will be assessed for any copies requested.

Roderick L. Bremby, Secretary
Kansas Department of Health and Environment